Appendix A

Tasks Tracked in CMS	Frequency	Assigned To
Test CPM Applications	5 year	Leak Detection Analyst
CPM – Review Training Materials	Annual*	Leak Detection Analyst
Archive and remove DOT required operational history files *in PLDS*	Annual	Leak Detection Analyst
Review Table 1 – Pipelines Without CPM	Annual	Operations Control Supervisor - Applications
Reboot Pipeworks Servers	Quarterly	Leak Detection Analyst
Tune thermals on all LeakWarn models	Monthly	Leak Detection Analyst

***-Annual, not to exceed 15 months**

Definitions

PipeWorks Definitions: Leak Detection and Batch Tracking are used on Magellan Pipelines where applicable.

PipeWorks is an integrated suite of software tools that assists pipeline personnel in the management and operation of a pipeline system. It is comprised of a number of modular applications that perform tasks such as **leak detection**, **batch tracking**, **hydraulic profiling**, **scraper tracking**, **batch scheduling**, **real-time modeling**, and training simulation.

These applications include a common set of utilities and tools that allow for the effective use of PipeWorks. This includes a graphical user interface (**GUI**), an object-oriented database management system and a number of ancillary tools and utilities. By using the same set of utilities for all of the modules, the software is easier to use and maintain and reduces learning time. This architecture also allows modules to interact, which reduces the individual complexity while allowing for sophisticated functionality.

PipeWorks incorporates standard third party software for its database (**ObjectStore**) and uses **JAVA** for the user interface. This combination ensures ease of interfacing with other customer systems and third party software. Another third party software package, Python, is used as a scripting language.

The PipeWorks architecture is designed for flexibility. As well as allowing various modules to coexist and interact on a single machine, modules may be installed on separate machines while still interacting. Where many pipelines are being modelled, several copies of one application may be created on one or more machines to manage the load. Several real time LeakWarn applications may be run on one (or more) machines while off-line applications such as PipeTrainer or the Transient Hydraulic Model may be run on the same or other machines *(Magellan does not currently employ the PipeTrainer or the Transient Hydraulic Model at this time)*.

1. LeakWarn

   LeakWarn is a robust and reliable pipeline integrity-monitoring tool. It includes the following functions:

   - Leak Detection – Detects leaks and alarms quickly and accurately.
   - Hydraulics Analysis – Provides details on real-time hydraulic conditions between measurement points along the pipeline.
   - Batch Tracking – Reports and tracks the position of batches, including ownership, ETAs, and batch quality.
   - Scraper Tracking – Reports the real-time location and ETA for one or more scrapers from launch to trap.
   - Product Tracking – Reports and tracks the composition of products including drag reducing agents (DRA).
   - Tank Management – Monitors tank inventories (not currently in use).

2. Third Party Software

   PipeWorks incorporates the following third party software:

   - ObjectStore (for data management)
   - Java (for the development of the user interface)

- Python (to create scripts)

PLDS – Pipeline Leak Detection Definitions: Used on the East Houston to El Paso Pipeline and the Ammonia Pipeline

The PLDS leak detection system is a Real Time Transient Model (RTTM) tool used to continuously measure fluid dynamic characteristics throughout the pipeline, during various movements and operation, including transients, to alert the Controller if certain tolerances for a given time period are exceeded.

Omega – Graphical user interface (GUI)

MIMIR - Communications interface between the PLDS server and the SCADA server

Detection of leaks

- The PLDS leak detection system detects leaks using the Model Compensated Volume Balance approach. Leaks are detected by continuous monitoring of the volume (mass) balance of the pipeline. Any hydraulic discrepancies generate imbalances. When an imbalance exceeds the threshold, an alarm is generated.
- Packing and unpacking the line, startups and shutdowns are tracked by using a combination of volume, meter flow, pressure and temperature readings. The pressure, temperature, product characteristics, and geometry of the line allow accurate calculation of the line inventory. The rate of change in the inventory is compared against the flow balance and determines the level of imbalances.
- Pipeline instrumentation such as pressure, temperature, gravity, accumulators, flow, valve status are monitored by SCADA and then sent to the PLDS system every three seconds for evaluation.
- Multiple averaging intervals provide maximum sensitivity for small leaks combined with fast response for large leaks. Magellan is currently utilizing the following periods (time-windows) on each of the segments that is being monitored:

  10 min   30 min   60 min
- Automatic tuning of leak detection is based on instrumentation repeatability.
- The monitoring of the East Houston to El Paso pipeline is accomplished with two types of sections, each having multiple averaging intervals:
  1) Whole of the East Houston to El Paso mainline.
  2) Pipeline divided into 7 sections delimited by 6 ultrasonic devices.
- When a leak alarm is generated in PLDS, the alarm is passed to the SCADA system to be displayed on the alarm display.
- In depth details about the alarms are available on the PLDS system.

Rate of Change (ROC) Definitions

ROC is used in analog pressure and flowrate records, to alert the Controller when a change in value exceeds the normal expected amount.

Magellan's standard is an ROC value of +10.0 and –10.0 that is entered in the ROC field of the flowrate parameter display.

Magellan's standard is an ROC value of +0.424 and -0.424 that is entered in the ROC field of the analog parameter display.

Scheduled PLDS Leak Detection Model Failover

- Scheduled with Controllers to avoid fail over during critical operations.
- Ensure backup PLDS server functioning correctly.
- Shutdown MIMIR interface to the production SCADA server.
- Monitor Vector processes to ensure successful fail over.
- Take corrective action if/when necessary.
- Start MIMIR interface on backup PLDS server to primary SCADA server, making the backup PLDS server now primary.
- Document.

PLDS Leak Detection Server Software Upgrades

- Scheduled and approved with Pipeline Operations via the Addition or modification of SCADA software process
* Performed by a 3rd party vendor
* Tested by a SCADA Analyst
* Certified by a SCADA Analyst
* Put into production by a SCADA Analyst & 3rd party vendor

System Integrity Plan Change Log		
Date	**Change Location**	**Brief Description of Change**
01-17-12	All	New Procedure – Material moved from 9.02-ADM-001
04-09-12	2.0 Description	Update grammar and correct spelling – not a version change

QUESTION #8i

EMERGENCY CODE RED OR INVESTIGATION PROCEDURE

PURPOSE:

Establish a standardized method for Emergency Event response, focusing on employee/public safety, environmental protection, minimization of the release volume, containment of released product, and containment in the primary vessel (pipeline, tank, etc…).

SCOPE:

This procedure is applicable for the following events: Code Red and Investigation.

All Controllers Shall:

1. Respond to x3200 (Magellan line) calls: **"MAGELLAN PIPELINE CONTROL – DO YOU HAVE AN EMERGENCY?"**
2. If no to emergency, assist as needed. If yes to emergency, fill out the form below:

Refer to "Sheriff Script" Maintained at Consoles and Provide Information Below to Responders

Console # | Date: | Time: | Controller Name:

Location of Incident: | Caller Name:

State: | City: | County:

Phone: | Is caller safe: | Injuries: | Has 911 Been Called:

Event Description:

Product Type: | Strong or Weak Odor: | Side Effects: | Source:

Product Primary Hazard: Gas = Fire/Explosion, Fuel Oil = Combustible/Irritant, Crude Oil = Flammable/Irritant, Ammonia = Irritant/Corrosive, NGLs = Fire

Flowing to: | Drip, Spray, Vapor Cloud: | Size:

Fire or explosion: | Soil, Water or Both: | Water type/name:

Color: | Any Company Signs: | Ignition Sources:

3. Classify event as Code Red or Investigation and proceed to appropriate procedure, below.

Code Red Event Definition:

- A SCADA indicated pipeline rupture.
- Notification reporting pipeline fire, explosion, or vapor cloud.

Note: All other events not Code Red are addressed as an Investigation.

Investigation Event Definition:

- Pinhole leak, seeper. (All Products)
- CPM alarms (example: LeakWarn, PLDS).

Note: If alarm determined to be false (cleared by static line pressure test or other method), document in LogMate only. If field investigation is required, document per Investigation procedure.

- Report of an unusual condition (example: dead vegetation, sheen on water or natural disaster).

Select one: Code Red Event _____ Investigation Event _____

Proceed to procedure for event type selected.

Code Red Event Procedure

All Controllers Shall:

1. Immediately perform a Code Red Event Shutdown of affected line and initiate control room Code Red Alarm.
   NOTE: Segmentation Rule (9.02-ADM-002 Startup and Shutdown Procedure) can be applied.
2. Immediately perform Code Red Event Shutdown of all potentially affected pipeline(s).

   Note: Verify upcoming console operations with team assisting with Code Red response.

   Note: Individual event circumstances may dictate that the order of the steps noted below are not followed in exact sequence.
3. Estimate Leak Size (from table below)

Summary of Pipeline Release Estimations

Estimate of Release Volume	
Pressure Change Observed per minute	**Volume To Report**
No confirming SCADA	Report Magellan **identified estimate** or **250 bbls.** **(Ammonia only – 250 bbls = 54,000 lbs)**
Greater than 250 psig	Report **3000 bbls** for pipeline diameters up to 12-inch **(Ammonia only – 3000 bbls = 648,000 lbs)**
	Report **6000 bbls** for pipeline diameters 14-inch and greater
50 to 250 psig	Report **250 bbls** for pipeline diameters up to 12-inch.
	Report **500 bbls** for pipeline diameters 14-inch and greater
0 to 50 psig	Report **250 bbls.**

4. Notify Sheriff's Office of affected counties (see Google Earth). Follow the Sheriff's script and give them all information noted in "Information Box" found near the top of this document.

5. Notify the NRC via an online form at http://www.nrc.uscg.mil/nrchp.html. CHRIS codes (Chemical Hazard Response Information System) are: gasoline = GAK, jet fuel or fuel oil = ODS, crude oil = OIL, ethanol = EAL, Propane = LPG, Butane = BUT, Ammonia = AMA.). If online not available, call NRC at 800-424-8802.

   Note: The NRC will ask whether or not the release has reached a water source. If it is known that a water source has been impacted, please answer "Yes" and then follow their further direction or questions. If it is known that a water source has not been impacted, please answer "No" and then follow their further direction or questions If it is unknown that a water source has been impacted, please answer "Unknown" and then follow their further direction or questions.

   For Ammonia only – *Within 15-minutes of initiating Code Red alarm, notify NRC.*

***For all other** – Goal within 15 minutes, limit within 1 hour of initiating Code Red alarm.*

For Ammonia only, also notify appropriate State Emergency Response Commission (SERC), Local Emergency Planning Commision (LEPC) and Environmental Specialist (ES).

Note: Preface all internal calls with the key words "CODE RED"

6. Make **initial** notification to the QI (Qualified Individual) designated on the On-Call List for affected area, or QI back-up if the first QI unavailable. If no QI available, notify Company Responders listed in District On-Call List and communicate information gathered.
   - Direct QI/Company responder to dispatch responders to rapidly close as many manual valves as possible upstream and downstream of potential release.
   - Request ETA of Company responder to the manual valves and/or suspected location of release.
   - If Company responder ETA is more than one hour, assist QI/Company Responder to determine quicker response.
7. Notify all 24x7 manned facilities on affected pipelines of Code Red.
   - Verify ROV (remote operated valve) status.
8. Call Company Release Reporting Number at 877-852-0015, following prompts on the call.
9. Communicate event via email to Code Red – RP/NGL or NH3 Code Red distribution list depending on release type (access through global address list in the Outlook address book) details of the release per template below.

   At (time) on (date), Operations Control has issued a Code Red for the (name the pipeline segment) in (name the city, state and county). This Code Red has been issued based on (identify what was observed in SCADA or what was reported by a 3rd party or company phone call). The pipeline in question was (idle or active) at the time of the call. The pipeline, and any other affected pipelines are currently shutdown and isolated. The NRC has been notified and provided a release estimate of (XXX) bbls of (XX) product grade. The NRC report number is XXXXX. The QI, (provide name of QI), has been notified and estimates responders will arrive at the release site in (time in minutes or hours) to begin on scene response and investigation. If you have any questions or concerns please call 918-XXX-XXXX (give appropriate supervisor or console number). Updates will be distributed as more information becomes available.
10. Identify and contact contractors working on affected pipeline, advising to keep clear of potentially hazardous areas. See Handover Sheet.
11. Notify Operations Control Supervisor. If none available, assign Supervisor tasks to assisting Controller(s).
12. Document actions (example: trending results, leak warn, leak warn, line balance, etc…) and additional information on Activity Log below.
13. If location of potential release unknown, trend data via PHD and use Leak Location Estimator below to determine release location (if applicable).

Leak Location Estimator

Leak Location Estimator	
	Enter miles (distance between first and second indication on pipeline)
	Enter seconds (time between first and second indication on pipeline)
0.0	Miles, Distance from first indication toward the second indication

- Enter distance in miles between first and second indication.
- Enter Time in seconds between first and second indication.
- Highlight the 0.0 with your mouse cursor and press F9. This will calculate the miles from the first indication toward the second indication.

14. Identify manual valves (via Google Earth or other available tools).

15. Make secondary call to QI or Company Responder.

    - Provide estimated leak location.
    - Provide nearest manual valves upstream and downstream of estimated leak location so they can be closed by field personnel.

16. List Company Responders contacted:

The Operations Control Supervisor shall:

1. Assume or appoint OCC (Operations Control Center) lead as point-of-contact and IC.
2. Notify OCC Manager of Code Red event.
3. Assist Controller to estimate location (see Leak Location Estimator).
4. Assist Controller and/or QI to determine nearest employee(s) available to close manual valves.
5. Determine need to call-out relief Controller for Controller on duty at the time of the release.
6. Determine need to perform a post accident drug and alcohol test on the Controller(s). If tested, must be within 2 hours of declaring Code Red. (24x7 Contact EMSI at 800-421-3674, Magellan account #274210014, we provide chain of custody.)
7. If emergency response contacts not completed by Environmental Specialist within 1 hour, make (or designate individual to make) following notifications: Link to TRP.
8. "Tag" units and valves on the affected pipeline or pipeline segment in SCADA so they cannot be operated by Operations Control. If Operations Control does not control the equipment, communicate to appropriate personnel to achieve task by other means (ex: Lockout/Tagout).
9. Coordinate initial event conference call, using 09-FORM-1124 as guidance (goal within 2 hours of event).
10. Transition IC to field via QI or designee of QI:
    - Ensure the individual transitioning IC to is qualified to take command.
    - Communicate all known details regarding the release.

4\. Assist in revising Activity Log as additional information acquired, ensuring revisions are communicated to the QI, including:
    - Document and prepare trends/activities pertinent to the operation or that occurred around release time.

12\. Authorize restarting operations of any pipelines shut down as a result of the event only after discussion and agreement with the QI and or IC.

13\. If QI and OCC unanimously agree Code Red is false alarm, or has otherwise been resolved, notify all internal stakeholders immediately.

14\. Prepare PHD data, Activity Log, Leak Location Estimator, After Action Review (following II timeline requirements) and phone records of event for retention in Code Red Event folder in LiveLink, ensuring that the following naming convention for the sub folder and documents are followed: a six digit date followed by the name of the Code Red Event (ex: 09-23-08 Tulsa 3N Release).

Investigation Event Procedure

All Controllers Shall:

Note: Do not use SCADA pressure readings to rule out a low-rate leak. Investigating a Potential Low-Rate Release must be used to make a determination. Remain in frequent contact with the On-Call Employee. Assist as necessary. Do not authorize restart of affected pipelines and/or equipment until Investigating a Potential Low-Rate Release has been completed and all investigation participants are in agreement that it is safe to restart the affected pipeline(s).

1. Determine potential release location and perform Investigation Event Shutdown of the affected pipeline and any other affected pipelines (see Segmentation Rule), per the Startup and Shutdown Procedure 9.02-ADM-002.

   Note: To eliminate the isolation of pressure transmitters, a *Staged Shutdown* may be performed by leaving designated valves open (yellow color valve number and box above valve) in order to perform line integrity monitoring.

2. Provide information to On-Call Employee that will investigate the event.
   - Request ETA of On-Call Employee to scene to investigate and make determination if is Investigation Event, Code Red Event or false alarm.
   - If the ETA is in excess of one hour, direct On-Call Employee to make arrangements to expedite response time (example: contact another employee that can respond more quickly).

   Note: If field employee response not available within one hour, call Sheriff to respond until employee arrives, requesting Sheriff isolate area as determines necessary until Magellan arrives.

3. Review and document:
   - Past line performance (example: line balance/LeakWarn, measurement integrity, pressures). For static line conditions (refer to the Normal Operations and Line Monitoring Procedure 9.02-ADM-017).

4. When On-Call Employee arrives at site and provides confident analysis, update status and communicate to Operations Control Supervisor. If unavailable, assume responsibilities of the Operations Control Center Supervisor

5. If review with OCC Supervisor determines there is a release, but it presents no public safety impact and is controlled, the field will follow their emergency response procedures found in SIP ADM-12.02, including release reporting procedures.

6. **For NH3**, Controller will solicit release amount and complete the notification process.

   In Minnesota: for all *suspected* release events (3rd party calls and Toxic Gas Alarms) or verified release events less than 20 gallons or immediately notify the Environmental Specialist who will make all appropriate internal and external notifications. If the primary ES cannot be reached, notify the secondary ES or the Company Release Reporting Number at 877-852-0015, initially pressing #6 for the Ammonia Distribution list, then completing the prompts to make a report.

   Outside Minnesota: for field verified releases less than 20 gallons notify the Environmental Specialist (ES) who will make all appropriate internal and external notifications if needed. If the primary ES cannot be reached, notify the secondary ES or call Company Release Reporting Number at 877-852-0015, initially pressing #6 for the Ammonia Distribution list, then completing the prompts to make a report.

   For field verified releases 20 gallons or more, initiate Federal NRC notification within 15 minutes of determination that a release has occurred using the amount from the field. Initiate State and Local notifications and the pertinent Environmental Specialist following NRC notification. Online reporting at http://www.nrc.uscg.mil/nrchp.html. CHRIS code for Ammonia = AMA. If online system unavailable, call NRC at 800-424-8802.

The Operations Control Center Supervisor shall:

1. Proceed to OCC (Operations Control Center), if situation/circumstances dictate.
2. Confirm shutdown of affected pipeline(s).
3. Review incident summary and assist On-Call employee and Controller to determine event status as Code Red Event, Investigation Event, or False Alarm.
   - **Code Red Event**: The Investigation Event constitutes a release or other situation that threatens to harm employees, the public, private property or the environment. Respond according to the Code Red Event Procedure.
   - **Investigation Event**: Do not use SCADA pressure readings to rule out a low-rate leak. Investigating a Potential Low-Rate Release must be used to make a determination. Remain in frequent contact with the On-Call Employee. Assist as necessary. Do not authorize restart of affected pipelines and/or equipment until Investigating a Potential Low-Rate Release has been completed and all Investigation participants are in agreement that it is safe to restart the affected pipeline(s).
   - **False Alarm**: After completing the Investigating a Potential Low-Rate Release Procedure, and the On-Call Employee confirms that there is no emergency, and a low-rate release has not occurred, the pipeline may be restarted according to the Startup and Shutdown Procedure 9.02-ADM-002. An Investigation Event false alarm is confirmed when the Investigation is complete and all participants (example: the AI Supervisor, Operations Control Supervisor, Area Supervisor, etc...) are in agreement that restarting the affected pipeline does not appear to pose a risk of harm to employees, the public, private property or the environment.

System Integrity Plan Change Log

Date	Change Location	Brief Description of Change	Field Impact
2/24/09	3.1.1	Added Ammonia Pipeline note.	
5/04/09	Table 2	Observed fire, explosion, large vapor cloud, or large spray/pooling of product either by Magellan or 3rd party. Changed reporting volume estimates to "Unknown" as applicable	
06/17/09	All	Reformatted – reviewed all.	
8/3/09	All	Took out Ammonia note, enhanced wording of leak location estimator.	
8/14/2009	All	Took out the words large for descriptions of vapor clouds and pooling of product. Added the email notification for Ammonia releases. Added the 250 bbls reportable to NRC (on ammonia releases) for reports of Code Red events from 3rd parties. Added notes to call the event by using the key words "CODE RED".	
9/11/9	All	Reformatted to numbers. Removed NH3 from Code Red procedure and reformatted for RP only procedure. Added spots for data entry below actions. Changed all reference of Notification Event to Investigation Event. Added Leak location Estimator. Added Code Red alarm step. Changed steps to contacting emergency (sheriff, NRC) prior to contacting QI.	
11/29/11	Table 1 Summary of Release volume	Took out the description column	N
10/05/09	All	Added Code Red and Investigation procedures together in one procedure. Added calling tree questions. Added requirement for AAR (after action review). Added event classification section.	
10/05/09	Code Red	Added requirement to call sheriff. Resorted actions order.	
10/19/09	All Controllers Shall	Section 1, added #2.	
10/28/09	Scope	Moved segmentation rule from Investigation section to scope section.	
10/28/09	Code Red definitions	Moved pinhole leak-seeper (NH3 only) to Investigation definition section (all products).	
10/28/09	Investigation – Supervisor Shall	Added Maintenance Event.	
10/30/09	Code Red section	Added new step 8 regarding contacting up/downstream locations.	
01/18/10	Code Red Controller Shall section, step 8	Edited to reflect 24x7 facilities and clarified task	
01/18/10	Code Red definition	Added verification/escalation by response agency	
01/24/10	Code Red Controller Shall section	Step 8 – Added clarification	
01/24/10	Investigation Event definition section	Added single low/low line balance and other alarms and note regarding documentation.	
02/01/10	Volume estimate table	Add bbls = lbs for Ammonia	No
02/02/10	Code Red – Supervisor Shall step 5	Added drug test must be complete within 2 hours of declaring Code Red.	No
02-22-10	Investigation Event	Added reference to Staged Shutdown	No
03-12-10	All	Changed all reference of Yellow Pad to LogMate	No
03-22-10	Code Red – Supervisor Shall, step 5	Added: perform a post accident drug and alcohol test	No
04-16-10	Code Red step 9	Added link to Magellan internal call script	No
04-16-10	Throughout	Added Leak Warn reference	No
06/17/10	Maintenance Event definition	Added requirement to notify ES.	No
06/17/10	Investigation Event: Controller Shall step 8	Added	No

06/17/10	Code Red Controller Shall:	Moved calling contractors on ROW to prior to calling Ops Con Supervisor	No
06/17/10	Code Red Controller Shall	Edited Summary of Pipeline Release Estimations to per minute	No
06/17/10	Code Red Controller Shall	Added note after step 2, stating that exact steps may not be followed in order due to event specific circumstances.	No
06/17/10	Definitions Section – Code Red	Added "*Visual*" in front of *Observed* in definition of Code Red.	No
07/12/10	Code Red Definitions	Added: Reported fire (active), explosion, rupture, vapor cloud off Magellan property	No
07/12/10	Investigation Event definition	Removed requirement to escalate to Code Red based on reporting requirements of ES.	No
08/12/10	Code Red – Controller Shall, step 5	Added requirement to call NRC within 1 hour of initiating Code Red alarm for all non-NH3 events.	No
01/01/11		Reviewed, no changes	No
02/09/11	Call script	Reformatted, added Fire/Explosion,	No
02/09/11	Classify event	Removed: *Begin analysis of events immediately, no longer than two (2) hours after receipt of information a leak or release may be occurring.*	No
02/09/11	Code Red Definition	Removed: *or spray/pooling of product*	No
02/09/11	Code Red – Controller Shall, step 5	Edited to reflect: *within 15 minutes, limit within 1 hour*	No
04/01/11	Code Red Definition	Edited.	No
04/01/11	Investigation Event Definition	Edited.	No
04/04/11	Code red Controller Shall	Edited NRC reporting process	No
05/12/11	Summary of pipeline release estimations	Changed the description of a third party call.	No
05/12/11	Scope	Moved Segmentation Rule to Startup/Shutdown procedure	No
05/12/11	Code Red	In Release Size Estimate table: Removed reference to consider Leak Detection System for volume estimate.	No
06/17/11	Investigation Event Controller Shall	Edited step 8, added step 9	No
06/17/11	Investigation Event OCC Supervisor Shall	Removed Maintenance Event.	No
06/24/11	Code Red	Removed Ammonia email requirement and replaced the supervisor requirement for email. Essentially, we took out the supervisor requirement for sending an email and shifted it to the controller.	No
06/24/11	Investigation Event, Controller shall	Added to call the sheriff if employee is not available to get to site within one hour.	No
9-7-2011	All Controllers Shall Section; Step 7	Modified step 7 to include who will be reporting to the federal, state and local personnel during investigation events.	Yes
12-12-11	Code Red All Controllers Shall Section: Step 5	Changed the NRC reporting to a call first and online report if a call cannot be completed.	No
12-13-11	Code Red All Controllers Shall section 5	Added note about answering water question with an unknown if it is not known whether a release has impacted water.	No
12/31/11		2012 annual review complete	

01/17/12	All	Matched the changes made to each checklist, took out editing of steps by the controller; added online reporting, added note to step 4 in Code Red – read sheriff the entire information box; switched steps 8 and 9 in Code Red; added step 4 to Ops Control Supervisor - Assist Controller and/or QI to determine nearest employee(s) available to close manual valves. Took out step 2 in investigation event – to call the supervisor and let him know before calling the field to investigate. Added step 9 in Supervisor code red	No
05/01/12	Code Red Step 2	Added "Refer to Sheriff Script" Maintained at Consoles and Provide Information Below to Responders" and "Product Primary Hazard" to table.	No
05/02/12	CHRIS CODE	Added Jet Fuel to definition	No

QUESTION #8i

INSPECTION OF RIGHT-OF-WAY PROCEDURE

1.0 PURPOSE

1.1 The purpose of this procedure is to establish a standardized method for inspecting pipeline right-of-way as required in 49 CFR Parts 192 and 195.

2.0 SCOPE

2.1 This procedure is applicable to federal and/or state jurisdictional pipelines and/or facilities. Elements of this program may be utilized in whole or part on non-jurisdictional assets as deemed appropriate.

2.2 Assets covered by Mitigation Plan: In addition to applicable Federal, State, and Local regulations, as well as Company guidelines, process, or best practices, Magellan Southern Expansion Assets (Houston – El Paso 18"/20") operates under the requirements of the Longhorn Mitigation Plan.

3.0 One Call Supervisor shall:

3.1 Ensure appropriate aerial patrol contracts are in place as described in the Aerial Patrol Services Requirements.

3.2 Maintain database describing patrol methods for each line (aerial or ground patrol)

3.3 Issue a One Call ticket for all new observations reported during Inspection of Right of Way.

3.4 Require Aerial Patrol Companies provide the following information for all new pilots:

3.4.1 Current OQ documentation to the One Call Group prior to a new pilot patrolling Magellan's Right of Way, utilizing ISNetworld tracking system.

3.4.2 Complete a Spot Check Report for Magellan to verify Drug & Alcohol Compliance.

3.4.3 Ensure a Pilot Effectiveness Checklist has been completed and approved for all new pilots.

3.5 Initiate a monthly review of all active pilots for OQ Certification.

3.6 Review each submitted Inspection of Right of Way Report for accuracy and completeness.

> **NOTE**: The conventional method of right-of-way inspection is by aircraft. Inclement weather, vegetation overgrowth, regulatory mandates, or restricted airspace, could render segments of the right-of-way insufficient for inspection via aircraft. In such cases alternative methods may include walking, driving, or other appropriate means of traversing the right-of-way.

4.0 All Employees shall:

4.1 Conduct ground patrol on schedule as required by the database listed in 3.2 above and the Maximum Interval Between Inspections table.

4.2 Patrol within the easement boundaries when possible.

4.3 Walk as closely as possible to the top of the pipeline to view ground surface over the entire easement.

4.4 Utilize equipment recommended for Right-of-Way Inspection:

4.4.1 Relevant pipeline or R-O-W maps.

4.4.2 Cell phone.

4.4.3 Digital camera and/or 35 mm Camera.

4.4.4 Voice activated recorder or log book to record observations.

4.4.5 GPS device

Maximum Interval Between Inspections		
	Highway and Railroad Crossings	**All Other**
Hazardous Liquids	Intervals not exceeding 3 weeks, but at least 26 times each calendar year.	Intervals not exceeding 3 weeks, but at least 26 times each calendar year.
Magellan Southern Expansion Assets (Houston-El Paso 18/20")	See the Assets Covered Per Mitigation Plan ROW Inspection Procedure for additional requirements per the Longhorn Mitigation Plan	See the Assets Covered Per Mitigation Plan ROW Inspection Procedure for additional requirements per the Longhorn Mitigation Plan

4.5 Conduct inspections more frequently if warranted by physical circumstances such as floods, significant increases in third party construction, agricultural activities, increased trenching activities, etc.

4.6 Accompany the pilot as often as necessary to:

4.6.1 Observe the condition of the rights-of-way.

4.6.2 Confirm the effectiveness of the pilot in the performance of duties. This will be completed for all new pilots and at a minimum of once each calendar year for existing pilots. Document results on the Pilot Effectiveness Checklist.

4.6.3 Validate the accuracy of the pilot's reporting.

4.7 Observe right-of-way for Suspected Releases, Emergency and Noteworthy Observations

4.7.1 Suspected Releases

4.7.1.1 Oil, petroleum product, vapor or other evidence of spills or discharges from Company pipelines and /or facilities.

4.7.1.2 Petroleum sheen on water near pipeline and/or facilities.

4.7.2 Emergency Observations

4.7.2.1 Dead vegetation over or near pipeline assets that could indicate a pipeline release.

4.7.2.2 Blasting or surface mining within 1/2 mile of a pipeline or R-O-W.

4.7.2.3 The following activities within **200 feet** of a pipeline right-of-way or if activity continued may come within **200 feet**

4.7.2.3.1 Excavation

4.7.2.3.1.1 Excavation activity (including agricultural equipment Deep Tilling, chiseling, etc., but excluding normal plowing) in Consent Decree HIRA locations within **75 feet** of the pipeline. Please contact Asset Integrity for specific information.

4.7.2.3.2 Construction or maintenance of any kind such as buildings, well derricks, fences, roads, streets, ditches, or waterways.

4.7.2.3.3 Construction or repair of levees or dredging

4.7.2.3.4 Debris hung up on pipeline and/or new washouts during or after flood conditions.

4.7.2.3.5 Idle Equipment: backhoes, dozers…etc…located on or near the ROW.

4.7.3 Noteworthy Observations

4.7.3.1 Washouts or impending washouts over or along the pipeline or immediate R-O-W.

4.7.3.2 Earth movement or subsidence with particular attention given to susceptible areas (e.g., slopes, rivers and etc.).

4.7.3.3 New deposits of harmful debris on rights-of-way.

4.7.3.4 Clearing of timberland, brush etc. over, across or along pipeline or R-O-W.

4.7.3.5 Any accumulation of debris on exposed pipelines crossing waterways.

4.7.3.6 Unintentional exposure of pipelines due to wind, water, general erosion, etc. Approved pipeline exposures will have a pipeline marker in place at each end of the pipeline exposure, where practical and appropriate.

4.7.3.7 Barges or large commercial watercraft anchored over pipeline or R-O-W waterway crossings.

4.7.3.8 Evidence of activity around a block valve or any other location along R-O-W that indicates vandalism or sabotage.

4.7.3.9 Any activity along the right-of-way that could, if not corrected, pose a hazard or compromise the safety, integrity or operation of pipelines and R-O-W.

4.7.3.10 Damaged or missing aerial or pipeline markings.

4.7.3.11 Overgrowth that prevents the inspection of surface conditions on or adjacent to pipeline or R-O-W.

4.8 Take photographs of:

4.8.1 Leaks or discharges

4.8.2 Damage to the pipeline (if observable) or significant damage to the condition of the right-of-way.

4.8.3 All suspected release and emergency observations.

4.9 For Suspected Releases, immediately contact Magellan's Operations Control Center at (800) 720-2417. Take actions outlined in Emergency Response Plans.

4.10 For Emergency Observations, report to immediate Supervision, and depending on severity to Operations Control. Provide the following (at a minimum) in verbal reports:

4.10.1 Observer's name

4.10.2 Line section name and milepost numbers. Facility names may be used in lieu of mileposts

4.10.3 Location of activity referenced to milepost, geographic features, landmarks or city

4.10.4 State and county, if known

4.10.5 GPS coordinates if available

4.10.6 Description of what was observed including all activities, any third party names obtained (companies) and proximity to pipeline or R-O-W.

4.10.7 Indicate that the observation is an emergency, if applicable

4.10.8 Any other relevant information obtained

4.10.9 Complete Right of Way Patrol Report by Aerial/Ground of all required observations as soon as practical following each inspection, but not more than three workdays following the completion of the ground patrol. Send completed reports to Magellan One Call Group. Retain Inspection of Right-of-Way Reports for two years.

4.11 Upon receipt of a completed Inspection of Right of Way Report, Magellan's One Call Group will generate and issue a "One Call Ticket" for any Emergency/Noteworthy Observations, to the appropriate Asset Locator.

4.11.1 Asset Locator shall as soon as practical, investigate the Observation(s).

4.11.2 Asset Locator shall document the date the Observation was investigated and all findings in the Comment Section of the One Call Ticket. It's critical to add enough information to clearly communicate ALL actions taken to protect the pipeline assets. If follow up is necessary due to weather conditions, future construction activities, etc., a statement of planned activities must be made and the Asset Locator must add the date and follow-up comments after the planned activity is complete.

4.11.3 In addition to completing the Comment Section, the Asset Locator shall close the One Call Ticket by selecting one of the following options: Located Facilities, Clear by Call, Clear by Knowledge, Clear by Map, Clear by Meet or Drive-by.

4.11.4 For conditions previously reported, it is not necessary to reinspect and generate a new report provided there is not a material change in the status or risks associated with the condition(s).

System Integrity Plan Change Log

Date	Change Location	Change By	Brief Description of Change
01/01/05			Reviewed, no changes
01/01/06	2.1	Troy Bronson	Replaced "Compliance is the responsibility of the Manager of Mid-Continent System Integrity (MCSI) accountable for the geographic area unless such responsibilities are delegated to others. With "Compliance is the responsibility of the Manager of Asset Integrity."
01/01/06	7.1.13	Troy Bronson	Added "Approved pipeline exposures will have a pipeline marker in place at each end of the pipeline exposure."
01/01/06	9.0	Troy Bronson	Added links
01/01/06	5.3.2.3	Troy Bronson	Added 5.3.2.3.3
01/01/06	6.0 NOTE:	Dan Egner	Changed "inaccessible" to " insufficient for inspection"
01/01/06	6.0	Dan Egner	Changed "WALKING, DRIVING…." To "Ground Patrol"
01/01/06	6.1	Dan Egner	Added subpart
01/01/06	6.2	Dan Egner	Major modification
01/01/06	6.3	Dan Egner	Added subpart
01/01/06	7.1.4.1	Dan Egner	Added subpart
01/01/06	7.2.2.1	Dan Egner	Added subpart
01/01/06	9.4	Dan Egner	Added Document
01/01/07	8.1.5	Dan Egner	Changed ROW inspection blasting reporting requirements from ¼ mile to 1/2 mile.
01-0107	8.2.61	Greg Walker	Added to Link to Inspection of ROW Report
01/01/07	8.2.5.1	Greg Walker	Changed responsibilities from field to One Call
05/03/07	6.0	Greg Walker	Moved aircraft contract language to a separate link.
05/03/07	2.0	Greg Walker	Removed Manager of Asset Integrity.
05/03/07	3.0	Greg Walker	Added Damage Prevention Supervisor
05/03/07	All	Greg Walker	Reformatted Structure
0717/07	All	Greg Walker	Conducted 2007 Annual Review, see change log
0717/07	3.4-3.6	Greg Walker	Added Pilot OQ certification review requirement
6-10-08	4.10	Greg Walker	Direct Asset Locators to add clear comments and a date of inspection, when closing 1-Call tickets generated from Inspection or Right of Way Reports. Conducted 2008 Annual Review, see change log
11-26-08	All	Greg Walker	Conducted 2008 Annual Review, see change log
			Deleted all references and links to Shell Consent Decree
12/18/08	4.7.1.6.1	Tim Boudreaux	Included excavation within HIRA locations statement.
9/4/09	All	Greg Walker	Conducted 2009 Annual Review, see change log
	2.2		Changed Longhorn references
	4.7		Added Suspected Release guidelines to procedure
	4.7.1.5.5		Added "idle equipment" observations
	4.9		Added notify Ops Control for Suspected Releases
01/01/10			Changed ref from Longhorn to Assets covered by Mitigation Plan
04/08/11	3.0	Dyan Gillean	Changed Mgr Damage Prevention & Design Service to One Call Supervisor
11/9/11	3.4	Dennis Vasicek	Added 3.4.2 and 3.4.3
11/9/11	4.4	Dennis Vasicek	Modified "Maximum Interval Between Inspections" table by removing references to natural gas pipelines
11/9/11	4.6.2	Dennis Vasicek	Added, "This will be completed for all new pilots and at a minimum of once each calendar year for existing pilots. Document results on the Pilot Effectiveness Checklist."
11/9/11	4.10.9	Dennis Vasicek	Removed reference to specific Magellan and Mitigation Plan forms and referenced the new combined "Right of Way Patrol Report by Aerial/Ground" form
11/9/11	4.10.9	Dennis Vasicek	Removed reference to natural gas pipelines.
12/31/11	All		2012 Annual Review complete

QUESTION #8k

CORROSION CONTROL PROGRAM

8-K

TABLE OF CONTENTS

1.0 SCOPE

1.1 This program is applicable to federal and/or state jurisdictional pipelines and/or facilities. Elements of this program may be used in whole or part on non-jurisdictional assets as deemed appropriate.

1.2 Texas Specific: In addition to applicable Federal, State, and Local regulations, as well as, Magellan guidelines, process, or best practices, certain pipeline system assets in Texas operate under the requirements of the Mitigation Plan.

2.0 EXTERNAL CORROSION CONTROL

2.1 External Coating 195.557, 195.559, 195.561, 16 TAC 8.305(2-3), 192.455(a)(1) and 192.461.

2.1.1 All buried or submerged newly constructed, relocated, replaced or otherwise changed steel lines shall be coated, including mainlines, terminal and station piping.

2.1.2 The external coating shall be applied on a properly prepared surface and have sufficient adhesion to the metal surface to effectively resist underfilm migration of moisture.

2.1.3 The coating shall be sufficiently ductile to resist cracking and have sufficient strength to resist damage due to handling and soil stress.

2.1.4 The coating shall have properties compatible with the cathodic protection system.

2.1.5 Electrically insulating type coatings shall have low moisture absorption and high electrical resistance.

2.1.6 The coated pipe shall be electrically inspected using a coating deficiency (holiday) detector prior to installation. Any damage found that impairs the effectiveness of the coating shall be repaired. Furthermore, the coating shall be protected from damage resulting from adverse ditch conditions or damage from supporting blocks.

2.1.7 Backfilling operations will be inspected to ensure that rocks, hard lumps of earth, etc. are not backfilled directly onto the pipe where they may damage the effectiveness of the pipeline coating.

2.1.8 Precautions will be taken to minimize damage to the coating during installation if coated pipe is installed by boring, driving, or other similar method.

2.1.9 Joints, fittings, and tie-ins shall be coated with material(s) compatible with the coating(s) on the pipe.

2.1.10 Coatings selection, application, and maintenance shall be performed as prescribed in Coatings – Selection, Applications, and Maintenance.

2.2 Cathodic Protection – 195.563, 195.565, 192.452, 192.453, 192.455 and 192.457

2.2.1 On facilities including newly constructed, relocated, replaced or otherwise changed pipelines, a cathodic protection system will be installed to mitigate corrosion.

2.2.2 A cathodic protection system will be installed for breakout tanks to mitigate corrosion. The systems shall be installed in accordance with API Recommended Practice 651, unless noted in this volume why compliance with all or certain provisions of API Recommended Practice 651 is not necessary for the safety of the breakout tank. Noted conditions that will cause compliance with 651 to not be observed may be but are not limited to tanks set on concrete, asphalt pads, or where studies conducted in accordance with API 653 indicate that corrosion will not affect the safe operation of the tank.

2.2.3 On facilities including newly constructed, relocated, replaced, or otherwise changed pipelines and tanks, a temporary cathodic system shall be provided as soon as practical during construction and a permanent cathodic protection system shall be provided within one year of completed construction.

2.2.4 Refer to Design and Installation of an Impressed Current Deep Groundbed and

Design and Installation of an Impressed Current Surface Groundbed for more information.

2.2.5 Soil Resistivity may influence the design considerations for cathodic protection systems as well as development of the Relative Risk Score for the line segment. See Soil Resistivity Overview for a general description of expected soil resistivity identified by state.

2.3 Corrosion Control Criteria 195.571, 192.463

2.3.1 Magellan adheres to the cathodic protection regulations in Part 195, "Transportation of Hazardous Liquids by Pipeline" and to the cathodic protection regulations in Part 192, "Transportation of Natural and Other Gas by "pipeline: Minimum Federal Safety Standards," of the DOT/Pipeline and Hazardous Materials Safety Administration Pipeline Safety Regulations.

2.3.2 When practical, Magellan requires maintaining a polarized potential of at least –0.850 volts as measured between the structure surface and a saturated copper-copper sulfate reference electrode that is in contact with the electrolyte (earth, soil, water, etc.). Where injurious aerobic bacteria has been identified, or is suspected, a polarized potential of -.950 volts or more negative is required. This voltage measurement shall be determined with the protective current applied and IR drop considered as described in paragraph 2.4 below.

2.3.3 Assets covered by the Mitigation Plan: For Tier II and Tier III areas, where practical a polarized pipe-to-soil potential of -.850 volts will be maintained. During close interval surveys, potential drops other than those across the structure to electrolyte boundary will be considered by interrupting the cathodic protection current source(s) and recording the ON" and "OFF" pipe-to-soil potentials Once established, the "ON" potential and "Off" potential will be utilized to correct future pipe-to-soil potential readings until such time as the system configuration or coating condition changes, or a new close interval survey is performed.

2.3.4 When a -0.850 volt potential is not practical, the following criteria are acceptable when approved by the Supervisor of Corrosion Control:

2.3.4.1 A minimum negative (cathodic) polarization shift of 100 millivolts

2.3.5 The 100-millivolt polarization decay criteria specify a minimum negative (cathodic) polarization voltage shift of 100 millivolts, measured between the structure surface and a reference electrode contacting the electrolyte.

2.3.6 Overprotection will be monitored and minimized through the analysis of data from annual pipe-to-soil surveys, close interval surveys, and pipeline visual inspections. A practical value of -1.2 volts (polarized) in reference to a copper/copper sulfate electrode will be used as value beyond which monitoring for overprotection shall be considered.

2.3.7 Refer to Cathodic Protection Criteria for more information.

2.4 IR Drop Consideration 195.571 and 192.463 (a)

2.4.1 IR drop is considered by taking potential readings directly over or as near as practical to the structure surface. The affect on the potential measuring circuit is kept to a minimum by using a high resistance voltmeter and being mindful of lead lengths and condition, contact to structure and contact to electrolyte.

2.4.2 Cathodic protection level should be evaluated utilizing Cathodic Protection Criteria.

2.5 New Construction 195.563 and 192.455(a)(2)

2.5.1 On newly constructed facilities and/or pipelines, a temporary cathodic system shall be provided as soon as practical during construction and a permanent cathodic protection system shall be provided within one year of completed construction.

2.5.2 Newly constructed facilities shall be included in and be managed in accordance with the Magellan System Integrity Plan within one year of completed construction.

2.5.3 On newly constructed facilities and/or pipelines, corrosion personnel, qualified under the Operator Qualification Ruling or with NACE Certification, shall be utilized to identify, mitigate, and monitor for inadequate cathodic protection and detrimental interference currents, prior to and during construction. Refer to Section 2.8, Foreign Crossings and Interference Currents and 2.14, Induced AC Corrosion below.

2.6 Cathodic Protection Surveys 195.573 (a) (d) and 192.465

2.6.1 A cathodic protection survey shall be conducted on each buried, in contact with the ground, submerged pipeline facility, and/or breakout tank in its pipeline system that is under cathodic protection once each calendar year with intervals not to exceed fifteen months. Pertinent survey information shall be recorded in the Cathodic Protection Data Manager (CPDM) within 30 days after the survey.

2.6.2 Assets covered by the Mitigation Plan: Pipe-to-soil surveys shall be performed annually not to exceed 15 months in Tier I areas and semi-annually not to exceed 7.5 months in Tier II and Tier III areas. Deficiencies will be resolved within one (1) year of discovery, except deficiencies of such a nature they present a more urgent threat to pipeline integrity, in which case corrections will be done immediately.

2.6.3 Pipe-to-soil readings shall be obtained at pre-assigned locations identified as necessary to determine the adequacy of cathodic protection. These locations can include, but are not limited to, test stations, cased crossings, and above ground appurtenances. Refer to Measuring a Pipe-to-Soil Potential for more information.

2.6.4 For aboveground breakout tanks where corrosion of the tank bottom is controlled by a cathodic protection system, the cathodic protection system shall be inspected to ensure it is operated and maintained in accordance with API Recommended Practice 651, unless noted in this volume why compliance with all or certain provisions of API 651 is not necessary for the safety of a particular breakout tank. Noted conditions that will cause compliance with 651 to not be observed may be but are not limited to tanks set on concrete, asphalt pads, or where studies conducted in accordance with API 653 indicate that corrosion will not affect the safe operation of the tank. Pertinent survey information shall be recorded in the Cathodic Protection Data Manager (CPDM) within 30 days after the survey.

2.6.4.1 Potential surveys taken on above-ground storage tanks should be conducted with an adequate level in the tank to maximize the contact of the tank bottom with the cushion material. Adequate level is typically at least 3 feet of liquid. Tank levels shall be recorded along with potential measurements. Tanks with inadequate levels shall be re-surveyed the same calendar year, once adequate levels are attained.

2.6.5 Additional corrosion control surveys, including but not limited to close interval pipe-to-soil surveys, will be conducted where practical and determined necessary by sound engineering practices. Indicators of the necessity to conduct such surveys shall include risk assessments, annual pipe-to-soil surveys, internal inspection data, pipe inspection, or other related corrosion information or testing.

2.6.6 At a minimum, close interval pipe-to-soil surveys will be considered under the following circumstances:

2.6.6.1 When identified through risk assessment including Section 6 analysis required by the Integrity Management Plan.

2.6.6.2 Assets covered by the Mitigation Plan: Close Interval surveys in Tier III areas will be conducted annually not to exceed 15 months. For Tier I and II areas close interval surveys will be managed through the Relative Risk Assessment Process within the System Integrity Model and conducted as necessary. Deficiencies will be resolved within one (1) year of discovery, except deficiencies of such a nature they present a more urgent threat to pipeline integrity, in which case corrections will be done immediately.

2.6.6.3 External Corrosion identified on the pipeline with a peak depth greater than 50% of the nominal wall, within 50 feet of a foreign pipeline crossing. Close interval survey may not be required if pipe-to-soil data collected at the location indicates that cathodic protection interference is not a concern.

2.6.6.4 Areas of inadequate cathodic protection as identified by pipe-to-soil surveys. Close interval survey may not be required if remediation of the low potentials includes the addition, modification, or adjustment of an impressed current cathodic protection that provides cathodic protection current beyond the area of inadequate potentials.

2.6.6.5 Areas of interference from a foreign cathodic protection current source. Locations of potential interference include but are not limited to, construction of new cathodic protection systems near the pipeline, changes in current output from foreign cathodic protection systems, and a reduction in cathodic protection levels without a corresponding reduction in output from the existing cathodic protection system.

2.6.6.6 In each case, the Close Interval Survey shall be conducted at spacing close enough to identify potential integrity threats and extend beyond the area of likely influence. Refer to Close Interval Pipe-to-Soil Survey and Testing for Interference Currents and Remedial Measures for more information.

2.7 Cathodic Protection Rectifiers 195.573 (c) and 192.465 (b)

2.7.1 Each cathodic protection rectifier shall be inspected for proper operation at least six times each calendar year with intervals between inspections not to exceed 2 ½ months. Pertinent survey information shall be recorded in the Cathodic Protection Data Manager (CPDM) within 30 days after survey. Refer to Rectifier Inspection, Cathodic Protection System Troubleshooting (Groundbed), and Rectifier Troubleshooting for more information.

2.7.2 Assets covered by the Mitigation Plan: Each cathodic protection rectifier shall be inspected for proper operation at least twelve (12) times each calendar year with intervals between inspections not to exceed 45 days. Deficiencies will be resolved within one (1) month of discovery, except deficiencies of such a nature they present a more urgent threat to pipeline integrity, in which case corrections will be done immediately.

2.8 Foreign Crossings and Interference Currents 195.573(c), 195.577, 16 TAC 7.86(5)(c), 192.465 (c) and 192.473

2.8.1 During each cathodic survey, a check of the integrity of each bond that exists across insulating flanges or other unions of pipeline facilities and each interference bond shall be made. Reverse current switches, diodes and interference bonds whose failure would jeopardize structure protection shall be inspected six times each calendar year with intervals between inspections not to exceed 2 ½ months. Pertinent survey information shall be recorded in the Cathodic Protection Data Manager (CPDM) within 30 days after the survey. Refer to Electrical Bond Inspection for more information.

2.8.2 Impressed current cathodic protection systems or galvanic anode systems will be designed and installed to minimize any adverse effects on existing underground metallic structures.

2.8.3 Stray current interference testing, including, but not limited to close interval pipe-to-soil surveys, will be conducted where practical and determined necessary by sound engineering practices. Indicators of the necessity to conduct such tests shall include annual pipe-to-soil surveys, internal inspection data, pipe inspection, or other related corrosion information or testing. Pertinent survey information shall be recorded on Magellan Foreign Line Interference Test Form. Refer to Testing for Interference Currents and Remedial Measures for more information.

2.8.4 Texas Intrastate Pipeline specific: Whenever suspected areas of interference are identified, testing will be conducted within 6 months to determine the extent of interference, and appropriate action will be taken.

2.8.5 For Interference Currents related to Induced AC refer to Section 2.14, Induced AC Corrosion below.

2.9 Electrical Isolation 195.575 and 192.467

2.9.1 Each buried or submerged pipeline shall be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit.

2.9.2 One or more insulating devices shall be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.

2.9.3 During each cathodic survey, a check of the integrity of insulating flanges or other unions of pipeline facilities shall be made if inadequate cathodic protection levels are found.

2.9.4 Shorted Casings

2.9.4.1 During each cathodic protection survey, readings may be taken at each cased crossing to detect any location where the carrier pipe may be shorted to the casing pipe.

> **NOTE**: For 192 regulated Natural Gas pipelines, readings shall be taken at each cased crossing to detect any location where the carrier pipe may be shorted to the casing pipe.

2.9.4.2 If the casing potential is within 100 millivolts of the pipeline potential, the casing shall be tested to determine whether a short to the carrier pipe is present. Corresponding classification data documenting the status of the casing shall be recorded in the Cathodic Protection Data Manager (CPDM). Refer to Shorted Casing Testing for more information.

2.9.4.3 Following internal inspection of a pipeline, the resulting smart pig data will be integrated with and compared to the casing information in the corrosion control database. Where the carrier pipe within the casing exhibits corrosion-caused metal loss, a risk evaluation will be conducted and action will be taken to mitigate the corrosion if deemed necessary.

> **NOTE**: For line sections integrity tested by hydrostatic test, a risk evaluation will be conducted at each shorted casing and action taken to clear the short and/or mitigate the corrosion if deemed necessary.

2.9.4.4 For 192 regulated Natural Gas pipelines, action will be taken to clear all shorted casings if practical.

2.9.4.5 Assets covered by the Mitigation Plan: If a shorted casing is verified, a plan of action shall be developed within three (3) months from the time of discovery. The practicality of clearing the short will be considered before any other measures are used. Action shall be taken to clear the short (a) in Tier I areas within six (6) months of development of the action plan; and (b) in Tier II and III areas within three (3) months of development of the action plan.

2.9.4.6 If clearing the short is impractical, the location can be monitored for leaks, or the casing/pipe interstice may be filled with a high dielectric corrosion inhibiting material. If the casing is monitored using leak detection equipment, the test must be performed twice each calendar year not exceeding 7.5 months. If monitored using internal inspection (smart pig) equipment, the inspection must be made at intervals as determined in the Magellan, Integrity Management Plan. These alternative measures, or any other measures approved by the Manager of Asset Integrity may be employed until it is practical to clear the short.

2.9.4.7 Assets covered by the Mitigation Plan: In the interim, from the time, a short is verified and action is taken to clear the short, the location will be inspected for corrosion or the casing /pipe interstice may be filled with a high dielectric corrosion inhibiting material. During any interval that a casing has been determined to be shorted, casing will be monitored. Tier I areas will be monitored twice per year at intervals not exceeding 7.5 months. Tier II and III areas will be monitored monthly at intervals not exceeding 6 weeks.

2.9.5 Insulating devices installed in areas where a combustible atmosphere is reasonable to foresee shall be installed with precautions to prevent arcing.

2.9.6 Pipelines in close proximity to electrical transmission tower footings, ground cables, or counterpoise, or in other areas where it is reasonable to foresee fault currents or an unusual risk of lightning, shall be protected against damage from fault currents or lightening and protective measures taken at insulating devices.

2.10 Test Leads 195.567, 192.469 and 192.471

2.10.1 All cathodically protected pipelines and breakout tankage shall have a sufficient number of test stations or other locations for electrical measurement to determine the adequacy of the cathodic protection system.

2.10.2 For design purposes, test lead spacing on pipelines shall be approximately one mile. This spacing shall be affected by conditions along the pipeline.

2.10.3 Breakout tankage will be monitored at the four quadrants.

2.10.4 The test leads shall be connected directly to the structure by Thermit welding or other process, which prevents stress concentration on the pipe and is approved by the Supervisor of Pipeline Integrity.

2.10.5 Test leads shall be maintained so that electrical measurements can be obtained in order to ensure adequate protection. For locations where repair of the test station is impractical, and a reading is necessary to determine the adequacy of cathodic protecting, an insulated probe rod may be used to contact the pipe and obtain the reading. This measure may be utilized until which time the test lead is repaired.

2.10.6 During installation, test leads shall be installed with enough looping or slack to prevent the test leads from undue stress or breakage during backfilling. Test leads installed in conduit shall be suitably insulated from the conduit. Refer to Attaching Cathodic Protection Test Leads for more information.

2.10.7 Bared test lead wire and bared metallic area at the point of connection to pipeline must be coated with an electrical insulation material compatible with the pipe coating and the insulation on the wire.

2.11 Exposed Pipeline Examination 195.569 and 192.459

2.11.1 When any buried pipeline is exposed, either intentionally or unintentionally, the exposed portion shall be visually inspected for evidence of external corrosion. Refer to Examining and Documenting the Condition of an Underground Pipeline or Related Facility When Exposed for more information.

2.11.2 When external corrosion requiring remedial action is found, further investigation will be conducted, circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine the extent of the corrosion in the vicinity of the exposed portion. Refer to Pipeline Defect Evaluation and Repair for more information.

2.11.3 If the extent of corrosion cannot be determined, plans and scheduling for further investigation or the use of an internal inspection device shall be developed based on the severity of the corrosion encountered.

2.11.4 If the exposed pipe is to remain exposed, proper pipeline markers shall be installed and the pipe shall be monitored for atmospheric corrosion in accordance with paragraph 3.1.1 below.

2.12 Stress Corrosion Cracking (SCC)

2.12.1 Basic SCC awareness information is available to operation and maintenance employees in Stress Corrosion Cracking Information.

2.12.2 The risks associated with SCC are identified and assessed per the Magellan Risk Assessment Methodology book, and include factors such as age of the pipeline, coating type, operating stress level, proximity of pump stations and history of SCC.

2.12.3 In the event that a pipeline system has experienced one or more confirmed incidents of SCC a systematic identification and examination of other potential locations of SCC will be conducted based upon the observations of conditions associated with the confirmed SCC incident.

2.12.4 Areas of the pipeline identified as having high susceptibility to SCC, or any other locations identified for SCC investigation, will be investigated per Stress Corrosion Cracking Investigation.

2.12.5 Pipe cutouts sent to a metallurgical lab for analysis will be investigated for SCC. Results of this analysis will be provided in a comprehensive report provided to Asset Integrity.

2.12.6 SCC field examinations will be performed by a NDE Technician trained in the detection of SCC on buried pipelines and will be documented in the Pipeline Maintenance Report.

2.12.7 If SCC is determined to be present, a review of the pipeline as defined in Section 6 of the IMP will be conducted, to be followed by a re-assessment interval recommendation per Section 7 of the IMP.

2.12.8 Annually, confirmed SCC occurrences will be reviewed to determine if changes to the SCC assessment criteria are necessary.

2.13 Microbiological Influenced Corrosion (MIC)

2.13.1 In the event that a pipeline system has experienced one or more confirmed discoveries of injurious MIC, or where accelerated corrosion from MIC is anticipated, a Bacteria Testing Protocol shall be established to evaluate future integrity threats from MIC.

2.13.2 The line specific protocol shall be utilized until such time that the threat from MIC has been assessed and appropriate mitigation actions have been taken.

2.13.3 Testing for MIC shall be conducted in accordance with Bacteria Testing – Serial Dilution Method.

2.14 Induced AC Corrosion 195.577 192.473

2.14.1 AC potential surveys shall be conducted on each buried, in contact with the ground, submerged pipeline facility, and/or breakout tank near high voltage power lines once each calendar year with intervals not to exceed fifteen months. Pertinent survey information shall be recorded in the Cathodic Protection Data Manager (CPDM) within 30 days after the survey. Refer to Testing for Induced AC and Remedial Measures for more information.

2.14.2 AC potentials greater than 10 volts will be evaluated to determine if additional testing or remedial actions are required. Refer to Testing for Induced AC and Remedial Measures for more information.

2.14.3 Remedial actions are required where through testing or calculations, AC current discharge densities are found to be at or greater than 100 A/m2 or AC potentials are greater than 15 volts. Remedial action may be required where AC current discharge densities range from 20-100 A/m2. Refer to Testing for Induced AC and Remedial Measures for more information.

3.0 ATMOSPHERIC CORROSION CONTROL

3.1 Inspection 195.581, 195.583, 192.479 and 192.481, and 16 TAC 8.305(1)

3.1.1 Facilities and/or pipelines, other than Breakout Tanks, shall be inspected at least once every three (3) calendar years with intervals not exceeding 39 months for onshore and at least once each calendar year, with intervals not exceeding 15 months, for offshore. Refer to Atmospheric Corrosion Inspections for more information.

NOTE: Atmospheric corrosion inspections on exposed pipelines must be conducted visually.

3.1.2 Assets covered by the Mitigation Plan: Facilities and/or pipelines, other than Breakout Tanks, shall be inspected annually for atmospheric corrosion. Refer to Atmospheric Corrosion Inspections for more information.

3.1.3 Breakout Tanks shall be inspected at least once every five (5) years with intervals not exceeding 60 months. Refer to Atmospheric Corrosion Inspections for more information.

3.1.4 Assets covered by the Mitigation Plan: Corrective action for deficiencies found during atmospheric surveys shall be determined and completed as soon as practical. Deficiencies will be resolved within one (1) year of discovery, except deficiencies of such a nature they present a more urgent threat to pipeline integrity, in which case corrections will be done immediately.

3.2 Coating 195.581, 195.583, 192.479 and 192.481

3.2.1 A suitable coating shall be applied to all new aboveground facilities to prevent atmospheric corrosion damage. Refer to Coatings – Selection, Applications, and Maintenance for more information.

3.2.2 A suitable coating shall be applied to all soil-to-air interface areas to prevent atmospheric and electrolytic corrosion damage. Refer to Coatings – Selection, Applications, and Maintenance for more information.

3.2.3 A suitable coating shall be applied to all aboveground facilities to prevent further atmospheric corrosion damage if, through the guidelines established in the Atmospheric Inspection Procedure, a Rust Rating of 2-G or worse is identified. Refer to Coatings – Selection, Applications, and Maintenance for more information.

3.2.4 The coating conditions on exposed assets shall be documented in the Atmospheric Corrosion database (CPDM).

4.0 INTERNAL CORROSION CONTROL

4.1 Introduction 195.579 and 192.477

4.1.1 The corrosive effects of pipeline cargoes (hazardous liquids or carbon dioxide) shall be investigated and if found to be corrosive, adequate steps shall be taken to mitigate internal corrosion. If steps are taken to mitigate corrosion, the effectiveness of the steps shall be monitored using corrosion coupons and/or other methods.

4.1.2 Circumstance or condition [such as those listed below] that could cause, promote, or increase the likelihood of internal corrosion should be promptly reviewed and internal corrosion mitigation plans implemented as appropriate.

4.1.2.1 Type of commodity

4.1.2.2 Flow rate

4.1.2.3 Velocity

4.1.2.4 Operating Pressure

4.1.2.5 Topography

4.1.2.6 Amount of foreign material and/or contaminants present in the pipeline and/or commodity stream such as sand, silt, water, or other materials that could cause or promote internal corrosion

4.1.2.7 Amount of sulfur, salts, acids, hydrogen sulfide, carbon dioxide or other corrosive material present and corrosive effect based upon partial pressures of material in the pipeline

4.1.2.8 Presence of microbes

4.1.2.9 Temperature

4.1.2.10 Pipe configuration, design, and material specifications

4.1.2.11 Operating conditions, including but not limited to, steady state conditions, slack line conditions, upset conditions in the pipeline system, and upset conditions in upstream facilities such as refineries or processing facilities

4.2 Product Evaluation

4.2.1 Crude Oil or natural gas containing water in the liquid phase, solids, and other corrosive constituents such as bacteria, H_2S, CO_2 and O_2, are considered potentially corrosive.

4.2.2 Refined Petroleum Products are evaluated using NACE TM 0172-2001, "Determining Corrosive Properties of Cargoes in Petroleum Product Pipelines". Petroleum products are considered "corrosive" if they do not meet at least a "C" rating on this test. Assets covered by the Mitigation Plan have a target NACE rating of "A"

4.2.3 Natural Gas Liquids are evaluated using ASTM D 1838, "Standard Test Method for Copper Strip Corrosion by Liquefied Petroleum Gases." Natural gas liquids are considered "corrosive" if they fail to meet the Number 1 classification on this test.

4.2.4 Free water in any product is potentially corrosive

4.2.4.1 Refer to Bacteria Testing – Serial Dilution Method for more information.

4.3 Internal Corrosion Mitigation

4.3.1 Adequate steps, including eliminating the possibility of free water, removing corrosive components, or injecting corrosion inhibitor will be taken whenever investigation of the corrosive effect of the product on the metal indicates it is necessary.

4.3.2 Cleaning pigs

4.3.2.1 Pipeline cleaning pigs should be utilized system wide on mainline piping. Refer to Perform Pigging Operations or location specific procedures as required.

4.3.2.2 To reduce the potential for unnecessary shut downs and/or unmanageable product contamination, pipelines with no history of pigging or those with significant amounts of known debris should not be pigged until adequate precautions and/or contingency plans have been developed.

4.3.2.3 The frequency for routine cleaning operations of mainline product piping should be 2 times per year, approximately every 6 months. The frequency for routine cleaning operations of mainline crude piping should be 26 times per year, approximately every two weeks. Cleaning of facility piping, pipelines without launching or receiving equipment, and/or other non-piggable sections should be conducted as required on a case by case basis. Pipelines transporting NH3 do not require routine pigging, but should be cleaned if excessive debris is identified prior to In-line inspection tool runs.

4.3.2.4 Pipeline pigging or repigging operations should also be considered when excessive debris is identified in the pipeline, following transportation of a corrosive (off spec) product, in preparation for integrity testing with a in-line inspection tool, following hydrostatic testing of a pipeline, etc.

4.3.2.5 Although the presence of debris in the receiving scraper trap does not necessarily indicate the quantity of material removed from the pipeline, it should be taken into consideration when determining the frequency of the cleaning pig operations. The physical condition of the pigs should also be taken into consideration, as a badly worn pig may be the result of excessive pipeline debris.

4.3.2.6 During normal cleaning operations, a combination cup and brush pig (1st pig) followed, as soon as practical, by a combination cup and disc pig (2nd pig) should be utilized.

4.3.2.7 Significant separation between the multiple pigs is not required and separation by more than a few yards will actually decrease the effectiveness of the operation.

4.3.2.8 Cleaning pigs should be maintained in accordance with the manufactures recommendations. Pigs worn beyond the manufactures recommend tolerance should not be used.

4.3.2.9 If a pig is to be run in a line which has not been pigged in many years or in a line which is suspected to be un-piggable, soft low density Polly Pigs should be utilized until confidence is achieved that normal cleaning pigs will successfully traverse the pipeline. Specialty pigs with tracking devices may also be warranted if there is concern that the pigs may become stuck in the pipeline.

4.3.2.10 Normal cleaning operations should be conducted at a continuous 3 ft/sec or less where practical.

4.3.2.11 Caution should be observed when pigging lines that start and stop. Debris may fall out in front of the pig causing the pig to become stuck.

4.3.3 Corrosion Inhibitor

4.3.3.1 When a corrosion inhibitor is used to mitigate internal corrosion, a sufficient quantity to protect the entire part of the system the inhibitor is designed to protect will be used. Assets covered by the Mitigation Plan: Inhibitors are required to control potential internal corrosion.

> **NOTE**: Whenever a corrosion inhibitor injection pump, internal coating, or other equipment to mitigate internal corrosion, is installed or removed a Pipeline Maintenance Report shall be completed.

4.3.4 When installing a tank bottom lining in an aboveground breakout tank, the lining shall be installed in accordance with API Recommended Practice 652 unless noted in this volume why compliance with all or certain provisions of API Recommended Practice 652 is not necessary for the safety of the tank.

4.4 Internal Corrosion Monitoring

4.4.1 When corrosion inhibitors are used to mitigate internal corrosion, coupons or other types of monitoring will be used to determine the effectiveness of the inhibitor and the potential extent of any corrosion. Refer to Coupon Handling and ER Probes for more information

> **NOTE**: Whenever new coupon holding devices or ER Probes are installed, a Pipeline Maintenance Report shall be completed.

4.4.2 At least twice each calendar year, and not exceeding intervals of 7 ½ months, corrosion coupons shall be removed from the test locations and forwarded to an appropriate laboratory for corrosion analysis.

4.4.3 Assets covered by the Mitigation Plan: At least three times each calendar year, and not exceeding intervals of 4.5 months, corrosion coupons shall be removed from the test locations and forwarded to an appropriate laboratory for corrosion analysis.

4.4.4 New corrosion coupons will be installed at this time. Any alternate or supporting corrosion monitoring methods will be accomplished at the same minimum frequency. Pertinent monitoring data shall be documented in the Internal Corrosion Database and/or the appropriate inspection forms. Refer to Coupon Handling and ER Probes for more information.

> **NOTE**: There may be instances in which a product is not corrosive, and therefore not inhibited. Corrosion coupons may be used to periodically evaluate these products. In these instances, coupon monitoring may be less frequent than twice per calendar year and 7 ½ month intervals.

4.4.5 Effectiveness of inhibitor will be based on the inhibitor's success in reducing the internal corrosion rate to an acceptable level. This level of acceptability may be different for each pipeline, but is typically <1 MPY for refined products. General corrosion rates can be classified as Low<1 mpy, Moderate 1.0 – 4.9 mpy. Sever >10 mpy.

4.4.6 Internal corrosion rates greater than >1 MPY on inhibited pipelines shall be followed up by contacting Product Services regarding injection rates, hydro-tests, or other unusual activities or circumstances. Action plans shall be developed if deemed necessary using sound engineering judgment.

4.4.7 Assets covered by the Mitigation Plan: Coupon corrosion rates over 1 mpy of general corrosion or pitting (including MIC) will trigger a detailed analysis directed by NACE certified corrosion control personnel. This analysis will include a review of incoming product quality sample data, inhibitor injection rates, bacteria testing and, if necessary, inhibitor performance testing. Deficiencies will be resolved within six (6) months of discovery, except deficiencies of such a nature they present a more urgent threat to pipeline integrity, in which case corrections will be done immediately.

4.5 Internal Examination 195.579(c) and 192.475 (b)

4.5.1 Whenever any pipe is removed from the pipeline for any reason, the internal surface shall be inspected for evidence of corrosion. Refer to Examining and Documenting the Condition of an Underground Pipeline or Related Facility When Exposed for more information.

4.5.2 When corrosion requiring remedial action is found, further investigation will be conducted both circumferentially and longitudinally (by visual examination, indirect method, or both) to determine the extent of the corrosion. Remedial actions will follow if necessary. Refer to Pipeline Defect Evaluation and Repair for more information.